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**PATENT**
HES 2000-IP-001848U1

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| Applicants: | Ronald E. Sweatman et al. | Art Unit: 1712 |
| Serial No.: | 10/082,459 | Examiner: Phillip Tucker |
| Filing Date: | February 25, 2002 | |
| For: | METHODS OF DISCOVERING AND CORRECTING SUBTERRANEAN FORMATION INTEGRITY PROBLEMS DURING DRILLING | |

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## SUPPLEMENTAL INFORMATION DISCLOSURE STATEMENT

By this statement, Applicants are submitting information of which they are aware and which they believe may be material to the examination of this application.

The filing of this statement should not be considered as a representation that a search has been made (see 37 C.F.R. § 1.97(g)), or an admission that the information cited is considered to be material to patentability as defined in 37 C.F.R. § 1.56 (see 37 C.F.R. § 1.97(h)). Furthermore, the filing of this statement should not be considered as an admission against interest in any manner (see Notice of final rulemaking, 1135 O.G. 13-25, at 25 (2-4-92)).

A Form PTO/SB/08B (formerly Form PTO-1449) is included herewith. The following information is listed:

## A. Non-Patent Literature Documents

1. Paper entitled "Remote Real Time Operations Assists in the Success of Wellbore Stability Solutions," by D. Kulakofsky et al., presented at the November 13-15, 2002 XIV Deep Offshore Technology Conference and Exhibition in New Orleans, Louisiana.

2. Paper entitled "The Difference between Fracture Gradient and Wellbore Pressure Containment and the Effect of Drilling Beyond Natural Pressure Limits" by Hong Wang et al., presented at the AADE 2003 National Technology Conference "Practical Solutions for Drilling Challenges," April 1-3, 2003 in Houston, Texas.

3. Paper entitled "New Solutions for Subsalt-Well Lost Circulation and Optimized Primary Cementing," SPE 56499, by R. Sweatman, R. Faul and C. Ballew, presented at the 1999 Annual Technical Conference, October 3-6, 1999 in Houston, Texas.

4. Paper entitled "In-Situ Reactive System Stops Lost Circulation and Underground Flow Problems in Several Southern Mexico Wells," SPE 59059, by F. Rueda and R. Bonifacio, presented at the 2000 International Petroleum Conference and Exhibition, February 1-3, 2000 in Villahermosa, Mexico.

## B. Non-Patent General Information

The following is a statement as to information not necessarily found in the above document or the documents or other information previously submitted to the Office in connection with this application.

The following jobs (treatments) were carried out by the assignee of the present application, Halliburton Energy Services, Inc. (hereinafter "HES"), on oil and gas wells prior to February 25, 2001, a date one year prior to the filing date of the present application.

(A) On March 16, 1996, a treatment was carried out in connection with a customer's well to seal weak subterranean zones that were 4,000 to 5,500 feet below the surface and losing well and formation fluids. The problematic zones were located below the bottom end (referred to as the shoe) of the cased hole. It had already been determined by the customer that the zones were losing well and formation fluids. HES was asked by the customer only to treat the problematic zones.

In carrying out the treatment, the results of a temperature survey, log information and other drilling operations data were first analyzed in order to determine the nature of the sealing composition and the procedure to be used for placing the composition in the weak zones. A sealing composition including 9,500 pounds of bentonite, 500 pounds of xanthan and 1,260 gallons of diesel was selected. The sealing composition was then commingled with a combination of mud and formation fluid and squeezed below the drill bit into the weak zones thereby imparting a high friction/extrusion pressure upon the flow path surfaces inside the formations. A substantial squeeze pressure was then achieved.

An equivalent pressure containment test on the shoe (an informal pressure containment test) was carried out on the newly formed seal to determine the approximate well bore pressure containment integrity, as expressed in pounds per gallon equivalent mud weight ("ppge"). Based on this test, it was confirmed that the well bore pressure containment integrity ("WPCI") had been increased to a value above the natural fracture pressure of the formation, and that well fluids were no longer being lost. The rig operator documented the increase in WPCI.

During the time frame of August to September of 1996, second and third jobs were carried out on the same well but in connection with weak zones at 8,750 to 9,800 feet below the surface. Again, it had already been determined by the customer that the zones were losing well and

formation fluids. HES was asked by the customer only to treat the problematic zones. Approximately 50 barrels of a sealing composition were commingled below the drill bit with 50 barrels of drilling mud to create a chemical reaction and form agglutinates that were injected into the weak zones. The sealing composition included 730.4 gallons of water, over 10 gallons of two different de-foaming agents, 50 pounds of caustic flakes, 907 pounds of soda ash (sodium carbonate), 935 gallons of styrene butadiene (a latex monomer), eight pounds of a dispersant and 5,344 pounds of an organophillic clay. The same overall job method utilized in the first job was utilized in the second and third jobs except the sealing composition was commingled with drilling mud only.

An equivalent pressure containment test on the shoe (an informal pressure containment test) was carried out on the newly formed seal to determine the approximate WPCI. Based on this test, it was confirmed that the WPCI had been increased to a value above the natural fracture pressure of the formation, and that well fluids were no longer being lost. The rig operator documented the increase in WPCI.

(B) During the months of November and December of 1996, four jobs were carried out in connection with a customer's oil and gas well in South Texas to seal weak subterranean zones that were approximately 13,490 to 14,400 feet below the surface and losing well and formation fluids. Again, it had already been determined by the customer that the zones were losing well and formation fluids. HES was asked by the customer only to treat the problematic zones. The sealing composition utilized in each job included 14.61 gallons/barrel water, 1 pound/barrel caustic soda, 18.27 pounds/barrel soda ash (sodium carbonate), 0.15 pound/barrel of a dispersant, 106.88 pounds/barrel organophillic clay and 18.29 gallons/barrel styrene butadiene, a latex monomer. The method utilized in each job first entailed the step of analyzing log information and other drilling

operations data to conceive the formulation for the sealing composition and design the placement procedure for the same. Next, the sealing composition was commingled with mud and squeezed below the drill bit into the weak zones thereby imparting a high friction/extrusion pressure upon the flow path surfaces inside the formations. A substantial squeeze pressure was achieved.

In each job, an equivalent pressure containment test on the shoe (an informal pressure containment test) was carried out before the sealant was cleaned out of the hole to determine the approximate WPCI of the formation. In each case, it was determined that the WPCI had been increased, and the rig operator documented the increase.

(C) Some time after December of 1996 and before late 2000, another series of jobs was carried out for the same customer but on a different well in South Texas to seal weak subterranean zones at approximately 11,060 to 11,100 feet below the surface. Again, it had already been determined by the customer that the zones were losing well and formation fluids. HES was asked by the customer only to treat the problematic zones. The same treatment composition and method utilized in connection with the jobs described in paragraph (B) above were utilized in connection with these jobs.

In each job, an equivalent pressure containment test on the shoe (an informal pressure containment test) was carried out before the sealant was cleaned out of the hole to determine the approximate WPCI of the formation. In each case, it was determined that the WPCI had been increased, and the rig operator documented the increase. For example, in connection with one of the jobs, it was informally determined and documented that the WPCI of the formation was increased to 2.3 ppge over the natural fracture gradient of the formation.

(D) Another series of jobs was carried out sometime after December of 1996 and before late 2000 on the same well to seal weak subterranean zones at approximately 11,060 to 13,650 feet

below the surface. Again, it had already been determined by the customer that the zones were losing well and formation fluids. HES was asked by the customer only to treat the problematic zones. The same treatment composition and method noted above in connection with the other South Texas wells described above were utilized in connection with these jobs.

In each job, an equivalent pressure containment test on the shoe (an informal pressure containment test) was carried out before the sealant was cleaned out of the hole to determine the approximate WPCI of the formation, and it was determined that the WPCI had been increased. The rig operator documented the increase in each case. For example, in connection with at least one of the jobs, it was informally determined that the WPCI of the formation was increased to 0.6 ppge over the natural fracture gradient of the formation.

(E) Also sometime after December of 1996 and before late 2000, a series of jobs was carried out for the same customer but on yet another well in South Texas to seal weak subterranean zones at approximately 11,240 to 13,760 feet below the surface. Again, it had already been determined by the customer that the zones were losing well and formation fluids. HES was asked by the customer only to treat the problematic zones. The same treatment composition and method utilized in association with the other wells in South Texas were utilized in connection with these jobs.

In each job, an equivalent pressure containment test on the shoe (an informal pressure containment test) was carried out before the sealant was cleaned out of the hole to determine the approximate WPCI of the formation, and it was determined that the WPCI had been increased. The rig operator documented the increase in each case. In connection with at least one of the jobs, it was informally determined that the WPCI of the formation was increased to 0.3 ppge over the natural fracture gradient of the formation.

(F) Also sometime after December of 1996 and before late 2000, a series of jobs was carried out for the same customer on yet another well in South Texas to seal weak subterranean zones at approximately 11,786 feet below the surface. Again, it had already been determined by the customer that the zones were losing well and formation fluids. HES was asked by the customer only to treat the problematic zones. The same treatment composition and method utilized in association with the other wells in South Texas were utilized in connection with these jobs.

In each job, an equivalent pressure containment test on the shoe (an informal pressure containment test) was carried out before the sealant was cleaned out of the hole to determine the approximate WPCI of the formation, and it was determined that the WPCI had been increased. The rig operator documented the increase in each case. In connection with at least one of the jobs, it was informally determined that the WPCI of the formation was increased to 1.0 ppge over the natural fracture gradient of the formation.

(G) Also sometime after December of 1996 and before late 2000, a series of jobs was carried out for the same customer on yet another well in South Texas to seal weak subterranean zones at approximately 12,000 feet below the surface. Again, it had already been determined by the customer that the zones were losing well and formation fluids. HES was asked by the customer only to treat the problematic zones. The same treatment composition and method utilized in association with the other wells in South Texas were utilized in connection with these jobs.

In each job, an equivalent pressure containment test on the shoe (an informal pressure containment test) was carried out before the sealant was cleaned out of the hole to determine the approximate WPCI of the formation, and it was determined that the WPCI had been increased. The

rig operator documented the increase in each case. In connection with at least one of the jobs, it was informally determined that the WPCI of the formation was increased to 3.0 ppge over the natural fracture gradient of the formation.

(H) On December 11, 1998, a job was carried out in connection with a well offshore of Nigeria to seal subterranean zones that were approximately 9800 feet below the surface. A shoe test had revealed that the WPCI of the formation was not sufficient to continue drilling. Accordingly, a treatment for sealing the formation was implemented. Again, it had already been determined by the customer that the zones were losing well and formation fluids. HES was asked by the customer only to treat the problematic zones. The same treatment procedure utilized in connection with the South Texas wells described above in paragraph (G) was utilized in connection with this job. A similar sealing composition was also utilized.

It was noted and documented by the rig operator that a 0.3 ppge increase in the WPCI over the fracture gradient of the formation, at the casing shoe, was achieved. Economic value was created for the customer. The WPCI was improved over the fracture gradient to allow safe overbalanced drilling deeper into a high pressure zone (without assurance of a sufficient WPCI, drilling into a high pressure zone (for example, under balanced to prevent losses)) would have carried the risk of pressure influxing into the well and causing an underground blowout.

In each of the jobs described by paragraphs (A) through (H) above, prior to the design of a specific sealing methodology by HES, it was determined that well bore fluid was being lost, or that formation fluid was flowing in, or that the WPCI was inadequate by halting drilling and carrying out an informal equivalent pressure containment test on the shoe before drilling deeper. Sometimes the WPCI was informally determined by changing the hydrostatic pressure with different density muds circulated into the hole or by an analysis involving repetitive pressure buildup and pressure fall off

carried out immediately after achieving the desired squeeze pressure of the sealant into the involved zone. However, the formal (documented pressure vs. rate or time curve analysis) step of determining the WPCI prior to pumping the sealing composition by increasing the density of or pressure exerted on the well bore fluid in the drilled well bore interval to an equivalent well bore fluid weight greater than or equal to the maximum hydrostatic pressure and friction pressure level to be exerted in the interval to determine if leak off occurs and if the pressure containment integrity of the interval is inadequate was either not carried out or not recorded and disclosed to the inventors.

In each of the jobs described in paragraphs (A) through (G) above, the zones were successfully sealed, and it was informally determined and noted by the rig operator that the WPCI had been increased above the natural fracture pressure of the formation. However, a formal leak off test documenting recorded pressure versus time curves or recorded pressure versus volume curves was either not carried out or not recorded and disclosed to the inventors. It was not known if the same result could be achieved in other wells; e.g., in wells having different conditions (temperatures, pressures, etc.) or associated with different types of formations. Furthermore, it was not known how the properties (e.g., density, rheology, etc.) of the drilling mud would affect the increase. The treatment data from the jobs was not obtained and fully analyzed by HES until beginning in the summer of 2000. Thus, formal, credible evidence that the WPCI of a formation can be increased above the natural fracture pressure of the formation in different types of formations and under various well conditions as well as in association with different types of drilling muds did not exist until the summer of 2000 or thereafter.

(I) In January of 2000, two jobs were carried out in connection with a customer's well in California to seal weak subterranean zones at approximately 17,242 to 17,401 feet that were

losing well and formation fluid. Again, it had already been determined by the customer that the zones were losing well and formation fluids. HES was asked by the customer only to treat the problematic zones. The sealing composition utilized in each job included 13.95 gallons/barrel of water, 88.1 pounds/barrel of a sealant formulation comprising organophillic clay, hydroxy ethyl cellulose, sodium carbonate and sulfonated acetone formaldehyde, 2.06 gallons/barrel of a stabilizer comprising alcohol ether sulfate and 19.85 gallons/barrel of styrene butadiene (a latex monomer). The method utilized in each job initially entailed the step of reviewing all logs pertaining to the drilling of the involved open-hole section. This review revealed certain suspect zones, which became the target of concern for the treatment. Next, a formation integrity test was conducted to determine the WPCI of the formation. Thereafter, a sealant job was designed to target the aforementioned suspect zones.

In carrying out the treatment, a spacer was pumped and followed by the sealing composition, which was followed by a second spacer. This material was then displaced to the drill bit in the hole. The annulus was closed and commingling of the sealing composition and the well bore fluid was initiated. The commingled products were then displaced at different concentrations and rates to the first suspect zone. The surface pressure response was reviewed real time during the job and a "first hit", i.e., the time when the sealing composition had reached the first zone of interest, was identified. At this time, displacement of the commingled products was continued until a majority of the sealing composition was placed in the suspect zone. The sealing composition was re-pressurized until such time as the engineering staff deemed that all of the suspect zones were sealed and the job was complete. The well was then opened up and circulation in the well was re-established. The drilling assembly was then slowly lowered into the hole to clean out the sealant remaining in the well bore. During this process, drilling parameters were monitored real time. As

the zones of interest were encountered, excessive torque was noted on the surface logs indicating that the sealant had indeed entered the targeted formation as expected.

In addition to the expected zones of interest, another zone, lower in the hole, also showed some torque indicating that a second location might need treatment. At this point, a formation test was carried out on the open-hole interval and it was determined that although the WPCI of the formation had been increased by the treatment to some extent, the expected increase had not been achieved. Accordingly, a second treatment was designed to target the lower zone. The same basic sealing composition and overall method utilized for the first zone was utilized for the second zone, except that a higher volume of the sealing composition was used. Upon cleanout as described above, the upper zones of interest again displayed excessive torque and the lower zones of interest displayed a higher torque than before when they were encountered by the drilling assembly indicating that the sealant had entered both the upper and lower formations as expected. Upon completion of the cleanout, a third pressure containment integrity test was performed and it was determined that the desired increase in the WPCI had been achieved. Accordingly, drilling was resumed by the customer. The well was drilled to total depth with no further losses in well and formation fluids.

Thus, in these jobs the zones were successfully sealed and it was determined that the corresponding WPCI was increased to a value above the natural fracture gradient of the formation. These were the first jobs that provided enough treatment and shoe and open-hole data (via formal leak-off and formation integrity tests conducted) to carry out a credible post-job analysis that included recorded pressure versus time and recorded pressure versus volume-rate curves. In these jobs, the step of determining the WPCI in the well bore interval prior to pumping the sealing composition into the interval by increasing the density of or pressure exerted on the well bore

fluid in the interval to an equivalent well bore fluid weight greater than or equal to the maximum hydrostatic pressure and friction pressure level to be exerted in the interval to determine if leak off occurs and if the WPCI in the interval is inadequate was carried out for the first time. Nevertheless, despite such an analysis and the fact that it showed that a significant increase in the WPCI above the measured fracture gradient had been demonstrated, many in the company were not convinced that a viable invention had been conceived and called the increase in WPCI a fluke.

The significant increase in the WPCI above the measured fracture gradient (expressed in ppge) was shown by a job report provided to the customer.

(J) On August 7, 2000, a method was carried out in connection with a customer's well to seal weak subterranean zones at approximately 17,730 to 17,750 feet. Again, it had already been determined by the customer that the zones were losing well and formation fluids. HES was asked by the customer only to treat the problematic zones. The sealing composition utilized comprised 465 gallons of styrene butadiene (a latex monomer), 11.6 gallons of alkyl phenoxy ether sulfate, 280 gallons of cycloaliphatic diepoxide and 84 gallons of amine crosslinker. The method utilized in each job entailed the steps of placing the drilling assembly approximately one yielded volume above the weak zone (the drilling assembly in the hole at the time of the treatment was actually tubing; no bit or bottom hole assembly was present due to the fact that cement plugs were set prior to the operations). At this time a formation test was run to determine the WPCI of the formation. Next, following a spacer, the sealing composition was pumped into the hole. Another spacer followed the sealing composition. The fluids were then displaced with well bore fluid until the leading edge of the spacer had reached the end of the tubing. The annulus was closed and commingling of the sealing composition with the well bore fluid was initiated. A first hit, i.e., where the surface pressure indicated that the sealing composition had reached the weak zone, was identified. The

displacement of the sealing composition into the zone was continued. The sealing composition was re-pressurized several times before the job was terminated. Once the job was complete, the assembly in the hole was pulled and a drilling assembly was run into the hole to clean out the sealing composition that remained in the hole. A review of the real time logs indicated that the sealant had in fact been displaced as designed.

A test was then carried out to determine the WPCI of the formation after the cleanout. It was determined that the WPCI had only been restored to its original level (a WPCI beyond the natural fracture gradient of the formation was not achieved). Nevertheless, the operator was able to drill ahead under the new well bore conditions to the total depth of the hole.

The sealing composition utilized in these jobs differed from the sealant compositions utilized in the other jobs conducted to date. Although it was hoped that the new composition would achieve the same results achieved in connection with the compositions used in the jobs previously carried out, the desired increase in WPCI over the natural fracture gradient did not occur.

(K) On approximately February 3, 2001, a job was carried out for the same customer for which the jobs described in paragraphs (B) through (G) above were carried out yet on a different well in South Texas. Again, it had already been determined by the customer that the zones were losing well and formation fluids. HES was asked by the customer only to treat the problematic zones. The job was carried out to seal weak subterranean zones that were approximately 11,950 to 13,100 feet below the surface. The same treatment and method utilized in connection with the other South Texas wells noted above were utilized in association with this job. It was noted that a 0.7 ppge increase in the WPCI over the natural fracture gradient of the formation was achieved.

(L) Sometime during early 2001, yet another job was carried out in connection with a South Texas well for the same customer to seal subterranean zones that were approximately 10,650

to 10,700 feet below the surface. Again, it had already been determined by the customer that the zones were losing well and formation fluids. HES was asked by the customer only to treat the problematic zones. The same treatment composition and method utilized in connection with the other South Texas wells noted above were utilized in these jobs. It was noted that 0.8 ppge increase in the WPCI over the natural fracture gradient of the formation was achieved.

The jobs described in paragraphs (B) through (G), (L) and (K) above are described in more detail in a paper presented in March of 2001 entitled "Treatments Increase Formation Pressure Integrity in HTHP Wells," AADE 01-NC-HO-42, and in a paper presented in May of 2001 entitled "Formation Pressure Integrity Treatments Optimize Drilling and Completion of HTHP Production Hole Sections," SPE 68946 (both cited in Supplemental Information Disclosure Statement filed on December 9, 2002).

General Information Regarding Development of Invention as Claimed:

Thus, many of the steps called for by the claims of the present application, as originally filed and amended by the preliminary amendment filed concurrently herewith, were included in jobs carried out prior to February 25, 2001, one year prior to the time the present application was filed (hereinafter the "Critical Date"). However, the overall method of discovering, diagnosing and correcting formation integrity problems in successively drilled subterranean well bore intervals, which is called for by all of the claims, was not carried out until after the Critical Date. For example, the treatments described in job (I) above were carried out in only one drilled section of the well. The steps of repeatedly carrying out formation pressure integrity tests and treating if necessary in successively drilled intervals; e.g., as the hole was drilled deeper, was not carried out in the above jobs. Furthermore, formal and credible evidence that the WPCI, expressed in ppge, can be increased above the natural fracture gradient of the formation in a variety of well and formation

conditions and in connection with different types of drilling mud was neither fully accepted and appreciated by HES nor presented to the public until after the Critical Date.

Due to skepticism within the company about the ability to increase the WPCI over a rock formation's natural fracture gradient or natural fracture pressure, a detailed analysis of the discovery leading up to the invention was not initiated until the summer of 2000. Beginning in the summer of 2000, an analysis of the treatment data from prior jobs allowed the WPCI, as expressed in ppge, and the extent of the increase therein to be formally documented with respect to prior jobs. The WPCI represents the known allowable pressure that can be applied to the formation without causing a loss or "leak off" of well bore fluid into the formation.

For example, with respect to the first job, described in paragraph (A) above, it was noted that the seal could contain a pressure of 18.6 ppge within the open hole. This improved WPCI was approximately 5.1 ppge higher than the natural fracture pressure for the weakest part of the open hole interval, which was 13.5 ppge. The treatment data on the second two jobs described in paragraph (A) above has not been analyzed to date.

With respect to the four jobs described in paragraph (B) above, the following was determined. The previous casing extended to 13,490 feet. The four jobs were carried out at depths ranging from 13,964 feet to 14,400 feet. The natural fracture pressure of the formation was determined to be 17.6 ppge at a point just below the casing shoe at 13,490 feet. It was measured during a shoe test in a relatively short open hole before drilling the rest of the hole to a total depth of 14,400 feet. The four jobs were carried out in several intervals of the entire open hole. The WPCI of the formation after each job was as follows:

First job: 18.4 ppge

Second job: 19.3 ppge

Third job: 20.1 ppge

Fourth job: 22.8 ppge

Thus, the total open hole increase in the WPCI of the formation over the natural fracture gradient of the formation was 5.2 ppge (3647 psi).

The analysis initiated in the summer of 2000 led to the publication of two technical papers, SPE 68946 entitled "Formation Pressure Integrity Treatments Optimize Drilling and Completion of HTHP Production Hole Sections," by R. Sweatman et al., presented at the European Formation Damage Conference May 21-22, 2001, and SPE 71390 entitled "New Treatments Substantially Increase LOT/FIT Pressures to Solve Deep HTHP Drilling Challenges," by S. Webb et al., presented at the 2001 Annual Technical Conference and Exhibition September 30, 2001 through October 3, 2001 (both cited in Supplemental Information Disclosure Statement filed on December 9, 2002). These papers provided formal and credible evidence that the WPCI, expressed in ppge, can be increased above the natural fracture gradient of the formation in a variety of well and formation conditions and in connection with different types of drilling mud.

HES confirmed that the inventive treatment could be successfully applied in typical ranges of well conditions and create seals that could change the WPCI of relevant exposed formations to a value higher than the natural fracture gradient of the formation by a technology project carried out by the company's "rock mechanics" scientists. This project, initiated in the spring of 2002, led to management approval to further develop the technology and plan a commercialization program relating thereto.

It is not believed that the above information is suitable for inclusion on Form PTO/SB/08A or Form PTO/SB/08B. Accordingly, such information is not included on the Form PTO/SB/08B accompanying this Statement.

The person making this statement is an attorney of record who signs below on the basis of information which has been supplied by the inventors and/or individuals associated with the filing and prosecution of this application and/or information in the attorney's file.

Respectfully submitted,

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| **INFORMATION DISCLOSURE STATEMENT BY APPLICANT** | Application Numb r | 10/082,459 |
| | Filing Date | 02/25/2002 |
| | First Named Inventor | Ronald E. Sweatman |
| | Art Unit | 1712 |
| *(Use as many sheets as necessary)* | Examiner Name | Phillip Tucker |
| Sheet 1 of 1 | Attorney Docket Number | HES 2000-IP-001848U1 |

**NON PATENT LITERATURE DOCUMENTS**

| Examiner Initials* | Cite No.[1] | Include name of the author (in CAPITAL LETTERS), title of the article (when appropriate), title of the item (book, magazine, journal, serial, symposium, catalog, etc.), date, page(s), volume-issue number(s), publisher, city and/or country where published. | T[2] |
|---|---|---|---|
| | 1 | D. KULAKOFSKY et al., Remote Real Time Operations Assists in the Success of Wellbore Stability Solutions , XIV Deep Offshore Technology Conference and Exhibition, Nov. 13-15, 2002 New Orleans, Louisiana | |
| | 2 | HONG WANG et al., "The Difference between Fracture Gradient and Wellbore Pressure Containment and the Effect on Drilling Beyond Natural Pressure Limits," AADE 2003 National Technology Conference "Practical Solutions for Drilling Challenges", April 1-3, 2003, Houston, Texas | |
| | 3 | R. SWEATMAN et al., "New Solutions for Subsalt-Well Lost Circulation and Optimized Primary Cementing," 1999 Annual Technical Conference and Exhibition, October 3-6, 1999, Houston, Texas | |
| | 4 | F. RUEDA, et al., "In-Situ Reactive System Stops Lost Circulation and Underground Flow Problems in Several Southern Mexico Wells," 2000 International Petroleum Conference and Exhibition, Feb. 1-3, 2000, Villahermosa, Mexico | |
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| Examiner Signature | | Date Considered | |
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*EXAMINER: Initial if reference considered, whether or not citation is in conformance with MPEP 609. Draw line through citation if not in conformance and not considered. Include copy of this form with next communication to applicant.
1 Applicant's unique citation designation number (optional). 2 Applicant is to place a check mark here if English language Translation is attached.